| TRANSMITTAL OF APPEAL BRIEF (Large Entity) | Docket No. SHL.0405US |
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In Re Application Of: **George A. Brown**

| Application No. | Filing Date | Examiner | Customer No. | Group Art Unit | Confirmation No. |
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| 10/551,288 | September 28, 2005 | Kenneth L. Thompson | 21906 | 3672 | 1537 |

Invention: **Method to Measure Injector Inflow Profiles**

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PATENT & TRADEMARK OFFICE

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Dated: **September 26, 2008**


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IN THE UNITED STATES PATENT AND TRADEMARK OFFICE

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| Applicant: | George A. Brown | § | Group Art Unit: | 3672 |
| Serial No.: | 10/551,288 | § | | |
| | | § | Examiner: | Kenneth L. Thompson |
| Filed: | September 28, 2005 | § | | |
| For: | Method to Measure Injector Inflow Profiles | § | Atty. Dkt. No.: | 101.0146<br>SHL.0405US |
| Customer No.: | 21906 | § | Confirmation No.: | 1537 |

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# APPEAL BRIEF

Sir:

The final rejection of claims 1-10 is hereby appealed.

Date of Deposit: September 26, 2008
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Nancy Meshkoff

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## REAL PARTY IN INTEREST

The real party in interest is the assignee Schlumberger Technology Corporation.

## RELATED APPEALS AND INTERFERENCES

None.

## STATUS OF CLAIMS

The application was originally filed with claims 1-6. Claims 7-10 were added. Claims 1-10 have been finally rejected and are the subject of this appeal.

## STATUS OF AMENDMENTS

No reply was made to the Final Rejection mailed on May 1, 2008. All amendments have therefore been entered.

## SUMMARY OF CLAIMED SUBJECT MATTER

The following provides a concise explanation of the subject matter defined in each of the independent claims involved in the appeal, referring to the specification by page and line number and to the drawings by reference characters, as required by 37 C.F.R. § 41.37(c)(1)(v). Each element of the claims is identified by a corresponding reference to the specification and drawings where applicable. Note that the citation to passages in the specification and drawings for each claim element does not imply that the limitations from the specification and drawings should be read into the corresponding claim element. In the following discussion, the independent claims are read on one of many possible embodiments without limiting the claims.

Independent claim 1 recites a method usable with a wellbore. The method comprises stopping injection of fluid into a formation that is intersected by a wellbore having an uphole section uphole of the formation and a formation section within the formation. (Specification at paras. [0014], [0020]; Fig. 1). The method further comprises observing temperature at least partially along the uphole section of the wellbore and at least partially along the formation section of the wellbore, while injection of the fluid is stopped. (Specification at paras. [0017]-[0018], [0024]; Fig. 3, curves 36, 38 and peaks 42, 44; Fig. 4, curve 50). The method also comprises re-starting injection of fluid into the formation in response to observation of a temperature peak in the uphole section of the wellbore. (Specification at paras. [0024]-[0025]; Fig. 4, curve 50 and peak 58A). The method further comprises observing, while re-starting injection of fluid is occurring, the movement of the peaked temperature fluid as it moves from the uphole section of the wellbore and across the formation section. (Specification at paras. [0025]-[0026]; Fig.4, peaks 58B-D). The method also comprises determining an inflow profile of the formation based on the movement of the peaked temperature fluid that is observed while re-starting injection of the fluid is occurring. (Specification at para. [0026]; Fig. 5).

Independent claim 8 recites a system usable with a well that comprises an injection system, an observation system and a processing system. The injection system injects and stops injection of fluid into a formation that is intersected by a wellbore having an uphole section uphole of the formation and a formation section within the formation. (Specification at paras. [0014], [0020]; Fig. 1). The observation system observes temperature at least partially along the uphole section and at least partially along the formation section. (Specification at paras. [0015]-[0018]). After injection of fluid is stopped, the injection system restarts injection of fluid into the

formation in response to an observed peak in temperature in the uphole section. (Specification at paras. [0024]-[0025]; Fig. 4, curve 50 and peak 58A). While re-starting of the fluid injection is occurring, the observation system observes movement of the peaked temperature fluid as it moves from the uphole section and across the formation section. (Specification at paras. [0025]-[0026]; Fig. 4, peaks 58B-D). The processing system determines an inflow profile of the formation based on the movement of the peaked temperature fluid observed while re-starting of the fluid injection is occurring. (Specification at paras. [0018], [0026]; Figs. 1 and 5).

At this point, no issue has been raised that would suggest that the words in the claims have any meaning other than their ordinary meanings. Nothing in this section should be taken as an indication that any claim term has a meaning other than its ordinary meaning.

## GROUNDS OF REJECTION TO BE REVIEWED ON APPEAL

**A. Claims 1-9 are rejected under 35 U.S.C. §102(b) as being anticipated by Anderson (U.S. Patent No. 4,832,121).**

**B. Claim 10 is rejected under 35 U.S.C. §103(a) as being unpatentable over Anderson (U.S. Patent No. 4,832,121) in view of Williams (U.S. Patent No. 6,497,279).**

## ARGUMENT

The claims do not stand or fall together. Instead, Appellant presents separate arguments for various independent and dependent claims. Each of these arguments is separately argued below and presented with separate headings and sub-headings as required by 37 C.F.R. § 41.37(c)(1)(vii).

### A. Claims 1-9 are rejected under 35 U.S.C. §102(b) as being anticipated by Anderson (U.S. Patent No. 4,832,121).

#### 1. Claims 1-5 and 8-9.

Anderson does not teach or disclose all of the limitations recited in claims 1-5 and 8-9. Anderson discloses a method for monitoring temperature during and after a well treatment. According to Anderson's teachings, temperature is monitored during injection of fluid into a packed interval to monitor and control fracture growth. During injection, observed temperature peaks move away from the largest volume of the fracture and towards the uphole and downhole sides of the fracture, thus delineating the fracture to provide an indication of its growth. *See* Anderson, Fig. 2, profiles 1-5. Once the fracture has reached the desired depth level, the well is shut in and, over time, the temperature peaks delineating the boundaries of the fracture interval disappear. Anderson, Fig. 2, profiles 6-9; 6:54-60. Anderson further discloses that when the well is produced and backflow from the fracture interval to the surface occurs, the temperature peak of the fluid moves uphole from the largest volume of the fracture towards the surface. Anderson, Fig. 2, profiles 10-14; 7:3-20. The fracture volume may be determined by monitoring the progressive development of this plume as production continues. Anderson, 7:26-36. Anderson also discloses that, as an alternative to backflowing fluid to the surface during production, the fracture volume could be determined by leaving the well shut in and monitoring the return of the temperature profile to equilibrium. Anderson, 7:43-47.

In contrast to the various teachings of Anderson, independent claim 1 recites a method usable with a wellbore that comprises a combination of steps having limitations that depend on other recited steps or that require the occurrence of recited events. For instance, claim 1 recites, among other elements, re-starting injection of fluid into a formation *in response to* observation of a temperature peak in the fluid in the uphole section of the wellbore, observing movement of the peaked temperature fluid *as it moves from* the uphole section *and across* the formation section

*while re-starting injection of fluid is occurring*; and determining an inflow profile of the formation *based on* the movement observed *while the injection is occurring.*

Independent claim 8 recites a system usable with a well that includes an injection system, an observation system and a processing system. Similar to claim 1, the observation system recited in claim 8 observes movement of the peaked temperature fluid *as it moves from* the uphole section *and across* the formation *while fluid injection is occurring.* The processing system determines an inflow profile of the formation *based on* the peaked temperature movement that is observed *while the fluid injection is occurring.*

In formulating the rejection of claims 1 and 8 in view of Anderson, many of these limitations appear to have been ignored. More specifically, the examiner has stated that Anderson anticipates the claims because Anderson discloses shutting in the well after an initial injection, monitoring temperature with sensors positioned above and within the formation, and injecting a subsequent treatment as the increased temperature formation fluid enters the wellbore while monitoring movement of the injection fluid in real time. (05/01/08 Final Office Action at page 2.) The examiner has further stated that Anderson discloses logging the temperature versus depth characteristics of the formation over time as an indication of the rate increased temperature fluid travels downhole. (*Id.*)

Notably, the examiner has not stated that Anderson discloses observing, while the injection is occurring, the movement of the peaked temperature fluid as it moves *from the uphole section and across the formation section* of the wellbore, as required by claims 1 and 8. This is because, in Anderson, while injection is occurring during the fracturing treatment, any peaked temperature fluid moves in the opposite direction to the direction recited in claims 1 and 8. More specifically, as shown in Fig. 2 of Anderson, the peaked temperature fluid moves *away* from the formation and *towards* a section of the wellbore that is either uphole or downhole of the formation during the fracturing treatment. Thus, in Anderson, *while injection is occurring*, it is not possible to observe a peaked temperature fluid that moves *from* a section uphole of the formation *and across* the formation, as required by claims 1 and 8.

The examiner also has stated that Anderson anticipates claims 1 and 8 because Anderson discloses shutting in after an injection to determine fracture volume profile as a result of the temperature profile reaching equilibrium. (05/01/08 Final Office Action at page 2.) In other words, the characteristics of the fracture are determined based on observation of the movement

of peaked temperature fluid *after injection has stopped* and while the well is shut in. Claims 1 and 8, in contrast, each require determining the inflow profile of the formation based on the movement of the peaked temperature fluid that is observed *while injection is occurring.* As explained in the specification of the present application, observing movement of the peaked temperature fluid as it moves from the uphole section and along the formation section during *injection* rather than during *shut-in* provides the advantage of substantially shortening the shut-in period. This is because, for wellbores that have been produced for a long period of time, temperature must be monitored along the formation for a substantial period of time during shut-in before information relevant to the determination of the inflow profile may be extracted from the warmback curves. (Specification, para. [0027]). Reading Anderson's disclosed method of determining formation characteristics based on temperature observations taken during the shut-in period essentially ignores claims 1 and 8's requirement that the temperature observation occurs while injection is occurring.

Based on the foregoing, it is respectfully submitted that Anderson, at minimum, does not disclose (a) observing the movement of peaked temperature fluid as it moves from the uphole section of the wellbore and across the formation while injection of fluid is occurring or (b) determining an inflow profile of the formation based on the movement of the peaked temperature fluid that is observed while injection of fluid is occurring. Because Anderson does not disclose these limitations, reversal of the rejection of claims 1 and 8 under 35 U.S.C. § 102(b) is respectfully requested.

Claims 2-5 and 9 are based on claims 1 and 8, respectfully. Thus, these claims are patentably distinguishable over Anderson for the same reasons as their base claims. As such, reversal of the rejection of claims 2-5 and 9 under 35 U.S.C. § 102(b) is respectfully requested.

**2. <u>Claim 6.</u>**

Claim 6 is based on independent claim 1 and further recites that determining the inflow profile of the formation comprises measuring the injection rate of fluid at the surface. Because Anderson determines characteristics of the formation based on temperature profiles observed during a shut in period (i.e., while injection is not occurring), the injection rate of fluid at the surface bears no relationship to Anderson's determinations. Accordingly, Anderson cannot—and does not—teach or disclose the limitations recited in claim 6. As such, reversal of the rejection of claim 6 under 35 U.S.C. § 102(b) is respectfully requested.

### 3. Claim 7.

Claim 7 is based on independent claim 1 and further recites using a distributed sensing system that comprises an optical fiber to sense temperature in the wellbore. The examiner has not pointed to anything in Anderson that teaches or even contemplates the use of an optical fiber to sense temperature. Indeed, in setting forth the obviousness rejection of claim 10 (which will be discussed below), the examiner admits that Anderson does not disclose such a limitation. Accordingly, because this limitation is missing from Anderson (as admitted by the examiner), reversal of the rejection of claim 7 under 35 U.S.C. § 102(b) is respectfully requested.

## B. Claim 10 is rejected under 35 U.S.C. §103(a) as being unpatentable over Anderson (U.S. Patent No. 4,832,121) in view of Williams (U.S. Patent No. 6,497,279).

Claim 10 is based on independent claim 8 and further recites a distributed sensing system that comprises an optical fiber disposed in the wellbore to sense temperature. The examiner has stated that Anderson discloses all of the limitations of claim 10 except for the use of fiber optics to determine temperature, which is disclosed by Williams. (Final Office action, at p. 3). However, for the reasons discussed in section A above, Anderson is deficient with respect to multiple limitations recited in claim 10. Because Williams does not compensate for these deficiencies, a *prima facie* case of obviousness of claim 10 in view of the proposed combination of Anderson and Williams has not been established. Accordingly, it is submitted that claim 10 is patentable over Anderson and Williams, and reversal of the obviousness rejection of claim 10 is respectfully requested.

## CONCLUSION

In view of the foregoing, Appellant respectfully requests that each of the final rejections be reversed and that the claims subject to this Appeal be allowed to issue.

Respectfully submitted,

Date: September 26, 2008

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## CLAIMS APPENDIX

The claims on appeal are:

1. A method usable with a wellbore, comprising:

stopping injection of fluid into a formation, the formation intersected by a wellbore having an uphole section uphole of the formation and a formation section within the formation;

observing temperature at least partially along the uphole section of the wellbore and at least partially along the formation section of the wellbore, while injection of fluid is stopped;

re-starting injection of fluid into the formation in response to observation of a temperature peak in the uphole section of the wellbore;

observing, while re-starting injection of fluid is occurring, the movement of the peaked temperature fluid as it moves from the uphole section of the wellbore and across the formation section of the wellbore; and

determining an inflow profile of the formation based on the movement of the peaked temperature fluid that is observed while re-starting injection of fluid is occurring.

2. The method of claim 1, wherein the temperature observing is performed using a distributed temperature sensing system.

3. The method of claim 1, wherein determining the inflow profile comprises computing the velocity of the peaked temperature fluid in the formation section of the wellbore.

4. The method of claim 3, further comprising plotting the velocity of the peaked temperature fluid as a function of depth in the formation section of the wellbore.

5. The method of claim 3, wherein the inflow profile indicates the percentage of fluid injected along the length of the formation section of the wellbore.

6. The method of claim 3, wherein determining the inflow profile further comprises:

measuring the injection rate of fluid at the surface; and

calculating the inflow profile in quantitative form.

7. The method of claim 2, wherein using the distributed temperature sensing system comprises using an optical fiber to sense temperature in the wellbore.

8. A system usable with a well, comprising:

an injection system to inject and to stop injection of fluid into a formation, the formation intersected by a wellbore having an uphole section uphole of the formation and a formation section within the formation;

an observation system to observe temperature at least partially along the uphole section of the wellbore and at least partially along the formation section of the wellbore,

wherein, after injection of fluid is stopped, the injection system re-starts injection of fluid into the formation in response to an observed peak in temperature in the uphole section of the wellbore, and

wherein, while re-starting of injection of fluid is occurring, the observation system observes movement of the peaked temperature fluid as it moves from the uphole section and across the formation section of the wellbore; and

a processing system to determine an inflow profile of the formation based on the movement of the peaked temperature fluid observed while re-starting of the injection of fluid is occurring.

9. The system of claim 8, wherein the observation system comprises a distributed temperature sensing system.

10. The system of claim 9, wherein the distributed temperature sensing system comprises an optical fiber disposed in the wellbore to sense temperature at least partially along the uphole section of the wellbore and at least partially along the formation section of the wellbore.

## EVIDENCE APPENDIX

None.

# RELATED PROCEEDINGS APPENDIX

None.